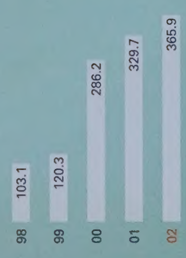
ALL DAY, EVERY DAY

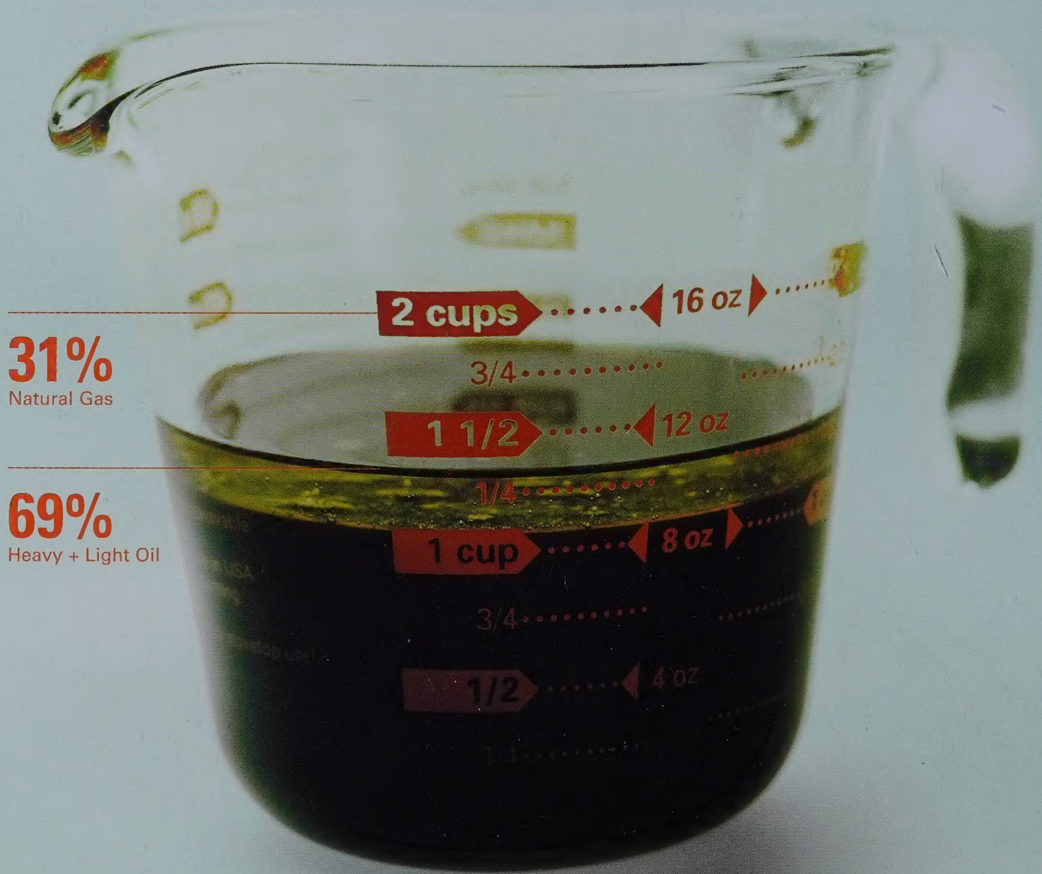
BAYTEX ENERGY LTD. 2002 ANNUAL REPORT

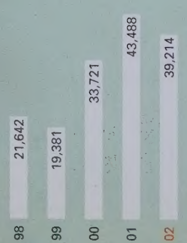
Corporate Profile Baytex is an independent oil and gas company engaged in exploration, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. We focus on enhancing our asset base through land acquisitions, seismic data interpretation, exploratory and development drilling, and property and corporate acquisitions. Our efforts are dedicated to properties that we believe will provide long-life reserves that will generate cash flow in the near term. Our excellent prospect inventory, disciplined capital spending approach and prudent financial strategy provide a solid foundation to deliver superior returns to our shareholders.

At Baytex, we know what side our bread is buttered on. Heavy oil is the backbone of our Company. It provides low-risk drilling opportunities, a low cost structure and allows for operations in a less competitive environment.

($ millions)
Revenue







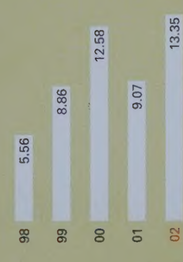
To measure up, we know that a dual commodity focus is necessary to maximize our opportunities. Our production profile at year-end 2002 was 69 percent oil to 31 percent natural gas.

(boe/d)
Production

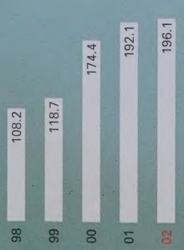
THE LAST DROP

As a heavy oil producer, the ability to grind down costs is critical to our success. In 2002, our field operating costs were $5.26 per boe of production and our finding and development costs were $7.32 per boe of established reserves.

($/boe)
Cash Flow Netbacks



IT ALL STACKS UP



Our long-term fixed differential supply agreement, our large inventory of drillable locations, our renewed financial flexibility and the innovation and drive of our people all stack up to an exciting 2003.

(mmboe @ 6:1)
Proved and Probable Reserves

ALL DAY, EVERY DAY

BAYTEX ENERGY LTD. 2002 ANNUAL REPORT

Highlights

	2002	2001
Financial		
($ thousands, except per share data)		
Petroleum and natural gas sales	365,860	329,700
Cash flow from operations	191,086	144,070
Per share – basic	3.65	2.91
– diluted	3.59	2.87
Net income (loss)	45,136	(137,107)
Per share – basic	0.86	(2.77)
– diluted	0.85	(2.77)
Net capital expenditures	126,468	375,853
Total net debt	362,775	379,061
Shares outstanding at		
December 31 *(thousands)*		
Basic	52,819	52,008
Diluted	57,945	56,476
Operating		
Production		
Conventional oil and NGLs *(bbls/d)*	3,154	5,152
Heavy oil *(bbls/d)*	23,967	26,533
Total oil and NGLs *(bbls/d)*	27,121	31,685
Natural gas *(mmcf/d)*	72.6	70.8
Barrels of oil equivalent *(boe/d @ 6:1)*	39,214	43,488
Reserves, proved and probable		
Oil and NGLs *(mmbls)*	162,168	162,555
Natural gas *(mmcf)*	203,536	177,420
Barrels of oil equivalent *(mboe @ 6:1)*	196,091	192,125

After enduring a most challenging 2001, during which Baytex's operations were unexpectedly and negatively affected by the widest heavy oil differentials in history, a sudden decline in natural gas prices and the aftermath of the September 11th events, we recovered and posted banner results in 2002.

With heavy oil differentials returning to their normal trading range, we accomplished our goals of resuming production growth and further strengthening our financial position. Cash flow for the year of $191 million and net income of $45 million are both Company records. Cash flow for the fourth quarter was $53 million or $1.00 per share, which was the best quarter of the year. This is somewhat unusual for Baytex as heavy oil differentials are historically widest in the fourth quarter. Often a forgotten commodity in our production mix, fourth quarter results reflect the natural gas leverage in our operations with our natural gas price averaging a year-best $5.29 per thousand cubic feet during the quarter. Looking ahead to 2003, these cash flow and earnings records could be short-lived as we are benefiting from even higher commodity prices.

With the objective of further strengthening our balance sheet, we maintained strict spending discipline during 2002 by limiting our capital program to projects that added immediate production and cash flow. We succeeded in growing our year-end exit production by 10 percent while spending less than cash flow from operations. While this is not an easy feat to accomplish in our capital intensive industry, we intend to apply the same formula in 2003 to grow production by spending less than cash flow. Our large number of drill-ready development locations for heavy oil and a high-quality inventory of natural gas prospects should allow us to accomplish this goal.

Over the past year, we have worked diligently to regain our financial strength. We completely repaid all of our bank loans. At year-end 2002, our total net debt was $363 million. As all of our outstanding debt is in US$ denominated term notes, the strengthening Canadian dollar to-date in 2003 has reduced this amount by over $20 million. Furthermore, on March 31, 2003, we completed the sale of certain assets in the Ferrier/O'Chiese area for $133.3 million. We intend to use the proceeds for debt reduction and general corporate purposes.

Our finding and development costs for 2002 were $7.32 per barrel of oil equivalent of established reserves. Over the last three years, we incurred total capital expenditures of $890 million with an average finding and development cost of $7.95 per barrel of oil equivalent of established reserves. We are particularly proud of our finding and development efficiency as this aggregate spending includes the acquisitions of OGY Petroleum and Triumph Energy in 2001, which were perceived to be completed at the high end of the valuation range.

Perhaps the most important achievement in 2002 was our signing of a five-year crude oil supply agreement with Frontier Oil and Refining Company. Under this agreement, we will be selling up to 16,000 barrels per day of our heavy oil production at a fixed Lloyd Blend differential of 29 percent of West Texas Intermediate (WTI) price. Simply put, this pricing arrangement has effectively removed the additional pricing

volatility normally associated with heavy oil on two-thirds of our corporate heavy oil production. It is recognized that the equity market generally imposes a discounted multiple on the stocks of heavy oil producers due to this pricing volatility. The impact of this contract on reducing pricing volatility should lead to an improved trading multiple.

It was also heartening to see our investors rewarded in 2002. The value of our subordinated notes have recovered from below par to the current 105 to 106 trading range. Our share price gained 94 percent during the year, making us the third best performing stock in the 42-company S&P/TSX Canadian Energy Index. To date in 2003, our stock has gained another 10 to 15 percent, amongst the best in the Energy Index.

With the asset divestiture program completed, Baytex is projecting average production of 28,500 barrels per day of oil and 69.0 million cubic feet per day of natural gas in 2003. The Company has commodity hedges covering approximately 45 percent of its projected oil production and 30 percent of its projected natural gas production for the year. Together with the Frontier supply contract, cash flow for the year is substantially protected against commodity price volatilities. Using the above production levels and pricing assumptions of US$25.00 for WTI oil, 25 percent for Lloyd Blend differentials to WTI, Cdn$6.35 for natural gas field price, $0.68 for exchange rate and interest rates at current levels, cash flow for 2003 is projected to be $200 million or $3.75 per share. A capital budget of $150 million is planned for the year, with approximately 55 to 60 percent allocated to heavy oil activities. Based on the above cash flow and capital program estimates, year-end total net debt is projected to be $165 million, or 0.8 times trailing cash flow.

On behalf of its Board of Directors, management of Baytex would like to thank the Company's shareholders for their continued support and our employees for their dedication over the past year. We are excited about 2003, and are committed to delivering superior returns all day, every day to our shareholders.

On behalf of the Board of Directors

Dale O. Shwed
President and Chief Executive Officer
March 31, 2003

AREAS OF OPERATION

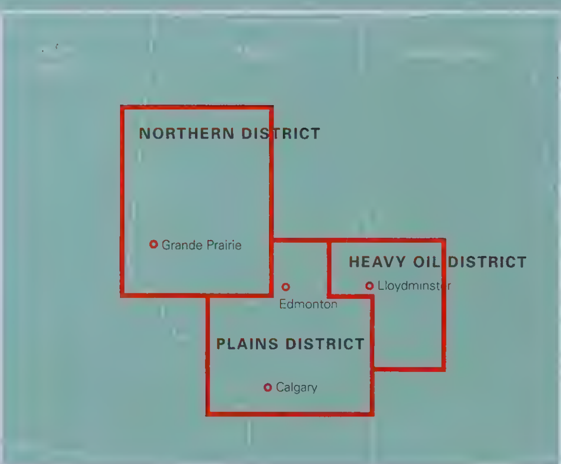
Areas of Operation

Operational activity in 2002 was balanced between regaining financial strength and ensuring renewed production growth. This balance was achieved through a focused drilling strategy that concentrated on heavy oil development, complemented by key natural gas exploration and development projects. Future opportunities were also provided through the acquisition of heavy oil assets at Ardmore, Alberta and the acquisition of 91,000 net acres of Crown land in Saskatchewan and Alberta.

Highlights during the year included:

- net capital expenditures totalling 66 percent of cash flow, resulting in significant strengthening of the Company's balance sheet;
- a 10 percent increase in exit production, despite the conservative capital program;
- finding and development costs of $7.32 per barrel of oil equivalent of established reserves;
- the addition of 165 heavy oil drilling locations with the acquisition of assets in the Ardmore, Alberta area;
- the signing of a heavy oil supply agreement that fixes the heavy oil differential on 16,000 barrels per day of heavy oil production for five years; and
- the successful development of our natural gas property at Ferrier, Alberta, resulting in a first quarter 2003 disposition for $133.3 million.

In order to manage the vast amount of information and expertise Baytex has in its main operating areas, the Company's technical staff is divided into three Districts. Baytex's Heavy Oil, Plains and Northern District teams are each given a focused mandate to take advantage of their strengths in their key operating areas in order to properly evaluate potential exploration and development prospects and acquisition opportunities, as well as managing their operations in the most efficient manner.



Heavy Oil District Baytex's Heavy Oil District continues to hold the Company's "bread and butter" properties, accounting for 66 percent of total production. With its low cost structure and less competitive environment, heavy oil provides Baytex with a superior return on capital investment. The Company's expertise in heavy oil operations has resulted in a low drilling risk, averaging a 94 percent drilling success rate over the last four years, as well as finding, development and operating costs that are below those of other commodities.

Baytex's heavy oil operations consist of cold conventional production from wells with multi-zone potential. Production is mainly from vertical and slant wells using progressive cavity pump technology to generate large volumes of sand and oil from one of the Cummings, Colony, McLaren, Waseca, Sparky, Rex and Lloydminster formations. Production from these wells usually averages between 40 and 100 barrels per day of lower gravity crude ranging from 12 to 18 API. Once produced, the oil is trucked or pipelined to markets in Canada and the United States for upgrading into lighter grades of crude or refined into petroleum products.

After enduring the widest heavy oil differentials in history in the fourth quarter of 2001, the first quarter of 2002 saw a significant narrowing of the heavy oil price differential and the return to profitability of the Company's heavy oil operations. With improved heavy oil economics early in 2002, Baytex quickly accelerated its drilling program and concurrently initiated a workover program to reactivate production that was shut-in near the end of 2001. Focus was turned to the development of the property Baytex acquired in 2001 at Cold Lake, Alberta along with continued development of the Company's existing properties at Baldwinton, Buzzard, Lashburn, Marsden and Silverdale in Saskatchewan.

During 2002, production in the Heavy Oil District averaged 25,710 barrels of oil equivalent per day, made up of 23,967 barrels per day of heavy oil and 10.5 million cubic feet per day of natural gas. The Company drilled 119 (113.1 net) wells in this district resulting in 103 (97.7 net) oil wells, three (2.5 net) gas wells, two service wells and 11 (10.9 net) dry and abandoned wells for a success rate of 91 percent. Total capital expenditures for the year were $101.6 million including property acquisitions of $41.5 million. Total undeveloped land in the Heavy Oil District at year-end 2002 was 315,596 net acres valued at $25.4 million.

The Company's pilot VAPEX (vapour extraction) project continued throughout 2002 with the injection of solvent into a low productivity heavy oil reservoir in the Carruthers, Saskatchewan area. This research and development project is based on injecting a propane, butane and natural gas mixture into the reservoir to reduce the viscosity of the heavy oil, thereby improving both the production rate and the ultimate recovery of oil from the reservoir. To date, Baytex has seen positive results with the breakthrough of solvent at the producing wells and enhanced production rates from three barrels per day to the 25 barrels per day range. The Company intends to continue this project throughout 2003 in order to gain further understanding on the effectiveness of this enhanced recovery technique. If successful, this technique could significantly increase recoverable reserves at Carruthers and could also be key to unlocking additional value from several of the Company's heavy oil reservoirs.

Heavy oil pricing has continued to be strong in the first quarter of 2003, allowing aggressive development of our heavy oil assets. Baytex has budgeted approximately $80 million for heavy oil capital spending in 2003, including the drilling of 165 wells. Activity will be focused on the development of the Company's Ardmore, Alberta property along with continued infill drilling at adjacent Cold Lake, Alberta and development drilling throughout Baytex's Saskatchewan properties.

Plains District After completing the sale of light oil assets in the first quarter of 2002, Baytex has focused its attention on the development of natural gas in the core areas of Ferrier/O'Chiese, Leahurst and Richdale within the Plains District.

During 2002, this district produced an average of 9,418 barrels of oil equivalent per day consisting of 43.8 million cubic feet per day of natural gas and 2,124 barrels per day of light oil and natural gas liquids. A total

of 42 (31.0 net) wells were drilled in the area resulting in one (0.4 net) oil well, 34 (23.6 net) gas wells and seven (7.0 net) dry and abandoned wells for a success rate of 83 percent. Total capital expenditures during the year included $48.0 million in exploration and development activities and net dispositions of $52.0 million. The Plains District contains 268,363 net undeveloped acres valued at $13.3 million at December 31, 2002.

The Company's development program at Ferrier/O'Chiese included the drilling of 18 (9.3 net) wells resulting in 17 (8.9 net) gas wells and one (0.4 net) oil well. Production in this area increased 30 percent during the year, reaching 3,300 barrels of oil equivalent per day in the first quarter of 2003. Despite the success in this area, the opportunity to capitalize on high natural gas prices prompted the Company to pursue the sale of its assets in this area in January 2003. This process has resulted in the sale of a majority of the producing assets in the Ferrier/O'Chiese area in March 2003 for proceeds of $133.3 million. Baytex is retaining certain exploratory lands and the relatively undeveloped Cow Lake property for future exploration and development purposes.

Leahurst, a property the Company has been involved in since 1993, and Richdale continued to provide shallow natural gas development opportunities during the year. Baytex successfully completed 11 (10.3 net) Mannville/Belly River natural gas wells and maintained production levels in excess of 16 million cubic feet per day throughout the year. Baytex was also successful in identifying natural gas targets through the use of 3-D seismic programs. The Company has identified a current inventory of 50 locations that can be drilled on lands in these areas.

At Bon Accord in Central Alberta, Baytex has successfully identified five locations with multi-zone, natural gas potential in the Ellerslie and Sparky formations. The Company is also pursuing low-pressure, in-fill natural gas locations in this area. Success in these projects will better utilize the large processing and transportation infrastructure that Baytex operates in this area.

The budget for this district for 2003 includes the drilling of 40 natural gas wells, including 20 development locations in Leahurst and Richdale. Capital spending of $40 million is planned for this district.

Northern District Baytex's Northern District demonstrated its ability to provide high impact gas plays during 2002 with the discovery of a Slave Point natural gas well in the Hamburg/Chinchaga area. This discovery has been followed up with another successful well in early 2003. The Company is planning to construct an eight million cubic feet per day gas plant in the area that is targeted to be on stream by mid-summer 2003.

During the year, the Northern District achieved average production of 4,086 barrels of oil equivalent per day including 18.3 million cubic feet per day of natural gas and 1,030 barrels per day of light oil and NGLs. Drilling in this district included 25 (23.8 net) wells resulting in one (0.5 net) oil well, 15 (14.8 net) gas wells, one (0.5 net) service well and eight (8.0 net) dry and abandoned wells for a success rate of 68 percent. Capital expenditures in the Northern District totalled $28.9 million, including property acquisitions of $0.6 million.

At Tangent/Dawson, Baytex continues to pursue natural gas opportunities in the Bluesky and Notikewin formations. During 2002, five (5.0 net) working interest wells were drilled in this area resulting in five natural gas wells. Three of these wells have been tied-in to a third-party natural gas facility and are producing at a combined 2.5 million cubic feet per day. The remaining two wells will be brought on stream as soon as additional pipeline and facility capacity is available. Baytex is also pursuing light oil opportunities in this area. Three wells are planned for 2003 testing Slave Point, Beaverhill Lake and Granite Wash light oil targets.

The Company continued to pursue development opportunities in its mature gas producing areas at Goodfish/Lafond and Nina/Darwin in northern Alberta with eight Bluesky gas wells drilled in 2002. These wells were tied in during the 2003 winter season, together with the drilling of six additional development wells. These activities will successfully replace production declines in these areas in 2003 and set up further development opportunities for next winter's program.

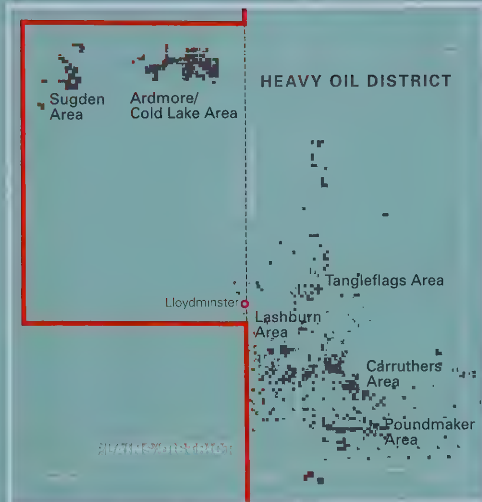
The Company has plans to spend $30 million in the Northern District in 2003 including the drilling of 19 wells. The Northern District continues to focus on finding opportunities within its 597,935 net acres of undeveloped land valued at $37.7 million at year-end 2002.

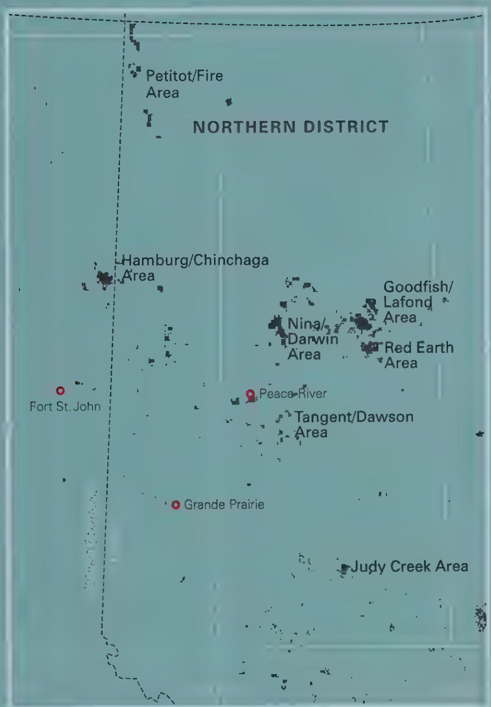
Production (Q4)
25,009 bbls/d
10.6 mmcf/d

Undeveloped Land
315,596 net acres
$25.4 million

2002 E&D Spending
$60.1 million

HEAVY OIL DISTRICT



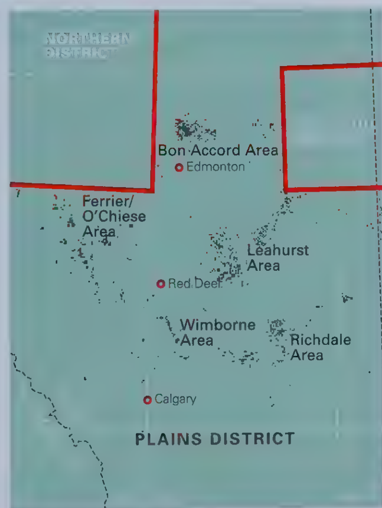


NORTHERN DISTRICT

Production (Q4)
1,076 bbls/d
17.9 mmcf/d

Undeveloped Land
597,935 net acres
$37.7 million

2002 E&D Spending
$28.3 million



PLAINS DISTRICT

Production (Q4)
1,833 bbls/d
43.3 mmcf/d

Undeveloped Land
268,363 net acres
$13.3 million

2002 E&D Spending
$48.0 million

Baytex Lands ■

OPERATIONS REVIEW

Land Baytex continues to maintain a sizable and focused undeveloped land base. At December 31, 2002, Baytex's undeveloped land holdings comprise 1,385,188 gross (1,181,894 net) acres. The average working interest of 85 percent represents a further improvement over the 82 percent at the end of 2001.

Baytex spent $9.2 million at Crown land sales in 2002 acquiring 91,000 net acres. Selective freehold leasing programs brought in an additional 8,800 net acres at a cost of $0.2 million.

Charter Land Services Ltd. has provided an independent evaluation of Baytex's undeveloped acreage as at December 31, 2002 and has attributed a replacement cost value to this acreage of $76.4 million compared to $89.5 million in 2001. The decline in value can be primarily attributed to the lower average crown sales prices paid in Alberta and Saskatchewan in 2002 compared to 2001.

The following table summarizes the undeveloped acreage owned by Baytex as at December 31, 2002. Undeveloped acreage means acreage on which we do not have a productive well and includes exploratory acreage.

Undeveloped Land Summary *(acres)*			**2002**			2001
	Gross	**Net**	**Average Interest**	Gross	Net	Average Interest
Heavy Oil District	**323,577**	**315,596**	**98%**	310,449	278,002	90%
Plains District	**346,548**	**268,363**	**77%**	385,585	273,031	71%
Northern District	**715,063**	**597,935**	**84%**	689,458	588,772	85%
Total	**1,385,188**	**1,181,894**	**85%**	1,385,492	1,139,805	82%
Value		**$76.4 million**			$89.5 million	

Drilling Activity		Exploratory		Development		Total
	Gross	Net	Gross	Net	Gross	Net
2002						
Crude oil	**1**	**1.0**	**105**	**98.6**	**106**	**99.6**
Natural gas	**10**	**9.8**	**41**	**30.1**	**51**	**39.9**
Service	**–**	**–**	**3**	**2.5**	**3**	**2.5**
Dry and abandoned	**7**	**7.0**	**19**	**18.9**	**26**	**25.9**
Total	**18**	**17.8**	**168**	**150.1**	**186**	**167.9**
Success rate *(%)*	**61**	**61**	**89**	**87**	**86**	**85**
Average working interest *(%)*		**99**		**89**		**90**
2001						
Crude oil	1	1	62	57.2	63	58.2
Natural gas	7	5	74	65.3	81	70.3
Service	–	–	3	2.4	3	2.4
Dry and abandoned	8	7.3	24	21.4	32	28.7
Total	16	13.3	163	146.3	179	159.6
Success rate *(%)*	50	45	85	85	82	82
Average working interest *(%)*		83		90		89

Oil and Gas Reserves Outtrim Szabo Associates Ltd., independent oil and gas reservoir engineers, prepared a report evaluating the Company's crude oil and natural gas reserves as of December 31, 2002. In connection with their review, Baytex provided Outtrim with land data, well information, geological information, reservoir studies, estimates of onstream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Outtrim also obtained other engineering, geological or economic data from public records, other operators and their non-confidential files.

Oil and Gas Reserves	Reserves (before royalties)		Present worth of reserves discounted at		
December 31, 2002	Oil & Liquids	Gas	0%	10%	15%
	(mbbls)	*(mmcf)*		*($ thousands)*	
Proved developed					
Producing	35,396	97,805	754,267	524,318	470,119
Non-producing	35,856	32,840	502,901	238,603	187,455
Proved undeveloped	38,122	20,830	492,632	254,201	197,069
Total proved	109,374	151,475	1,749,800	1,017,122	854,643
Probable	52,794	52,061	802,190	362,704	277,104
Total proved and probable	162,168	203,536	2,551,990	1,379,826	1,131,747

Pricing Assumptions	WTI at Cushing, Oklahoma	Light oil at Edmonton	Heavy Oil 12 API at Hardisty	Alberta spot gas price
	(US$/bbl)	*(Cdn$/bbl)*	*(Cdn$/bbl)*	*(Cdn$/mcf)*
2003	26.00	39.73	25.73	5.66
2004	23.35	35.56	24.06	5.07
2005	21.63	32.88	22.13	4.63
2006	21.96	33.37	23.12	4.65
2007	22.29	33.87	23.62	4.68

Reserve Reconciliation	Crude oil and NGLs *(mbbls)*			Natural gas *(mmcf)*		
	Proved	Probable	Total	Proved	Probable	Total
December 31, 2000	105,022	48,038	153,060	98,048	30,202	128,250
Discoveries and extensions	11,049	4,054	15,103	19,705	3,421	23,126
Acquisitions	12,832	7,241	20,073	61,162	18,050	79,212
Dispositions	(7,593)	(5,809)	(13,402)	(6,527)	(1,725)	(8,252)
Revisions of prior estimates	477	(1,190)	(713)	(11,887)	(7,181)	(19,068)
Production	(11,566)	–	(11,566)	(25,848)	–	(25,848)
December 31, 2001	110,221	52,334	162,555	134,653	42,767	177,420
Discoveries and extensions	8,588	5,059	13,647	53,443	13,114	66,557
Acquisitions	6,675	2,364	9,039	1,738	447	2,185
Dispositions	(6,104)	(3,449)	(9,553)	(19,721)	(4,118)	(23,839)
Revisions of prior estimates	(107)	(3,514)	(3,621)	7,844	(149)	7,695
Production	(9,899)	–	(9,899)	(26,482)	–	(26,482)
December 31, 2002	109,374	52,794	162,168	151,475	52,061	203,536

Reserve Life Index

December 31, 2002	Q4 – 2002 production	Total proved	Proved and probable
Crude oil and NGLs *(bbls/d)*	27,918	10.7	15.9
Natural gas *(mmcf/d)*	71.8	5.8	7.8
Oil equivalent *(boe/d)*	39,890	9.2	13.5

Investment Efficiency	2002	2000–2002 3-year average
Capital expenditures *($ thousands)*	**126,468**	296,791
Finding and development *($/boe)*		
Proved	**7.77**	8.58
Proved + 1/2 probable	**7.32**	7.95
Proved + probable	**6.92**	7.40
Cash flow netbacks *($/boe)*	**13.35**	11.53
Reserve recycle ratio		
Proved	**1.7**	1.3
Proved + 1/2 probable	**1.8**	1.5
Proved + probable	**1.9**	1.6
Reserve replacement ratio		
Proved	**1.1**	2.4
Proved + 1/2 probable	**1.2**	2.6
Proved + probable	**1.3**	2.8

Net Asset Value

December 31, 2002 *($ thousands, except share data)*	DCF 10%	DCF 15%
Established (proved plus 50 percent probable) reserves	1,198,474	993,195
Undeveloped land	76,391	76,391
Long-term debt and working capital	(362,775)	(362,775)
Stock option proceeds	24,869	24,869
Net asset value	936,959	731,680
Diluted shares outstanding *(thousands)*	56,540	56,540
Net asset value per diluted share *($)*	16.57	12.94

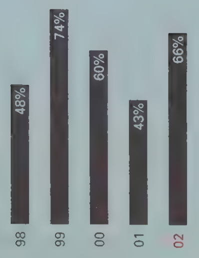
Marketing *Crude Oil* World crude oil prices remained strong in 2002, buoyed by the expectation of supply disruptions from a Middle East conflict. Benchmark West Texas Intermediate (WTI) crude oil prices averaged US$26.08 per barrel in 2002, virtually unchanged from US$25.90 per barrel in 2001. The five-year average for WTI is US$23.17.

Oil prices began the year around US$20.00 per bbl as the U.S. economy was slow to recover from the events of September 11, 2001. However, as political events in Venezuela and Iraq unfolded during the year, oil prices continued to strengthen reaching US$29.39 in the month of December. Baytex's conventional crude oil and natural gas liquids prices averaged $33.86 per barrel in 2002 compared to $33.65 per barrel in 2001.

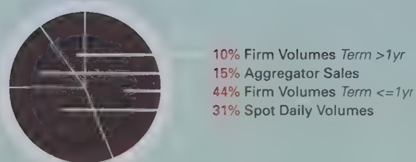
Canadian heavy oil prices benefited from reduced domestic supply due to curtailed spending and reduced supplies of Venezuelan heavy and sour crudes into U.S. markets in late 2002. The differential between WTI and Lloyd Blend prices in Alberta averaged US$6.58 per barrel in 2002 (25 percent of WTI) compared to US$10.72 in 2001 (42 percent of WTI), with five-year averages at US$7.08 and 31 percent of WTI. Baytex's heavy oil prices enjoyed the lower differentials, averaging $26.39 per barrel in 2002, up sharply from $16.69 per barrel in 2001.

In October 2002, the Company announced the signing of a five-year crude oil supply agreement with Frontier Oil and Refining Company. The agreement calls for Baytex to deliver 9,000 barrels per day of blended heavy oil to Frontier in January 2003, increasing to 20,000 barrels per day in October 2003 and throughout the remaining term of the arrangement. Prices will be fixed at 71 percent of WTI or a 29 percent Lloyd Blend differential, thus significantly reducing the volatility of the Company's cash flows from its heavy oil operations.

Natural Gas Natural gas prices were weaker in 2002 compared to 2001, as high inventory levels depressed values throughout much of the year. Unusually cold temperatures across eastern North America drew inventories down late in the year as demand for natural gas and heating oil far exceeded normal levels. U.S. gas prices, represented by the NYMEX futures contract, averaged US$3.25 per thousand cubic feet in 2002, down from US$4.38 per thousand cubic feet in 2001. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $4.05 per thousand cubic feet in 2002 compared to $5.44 per thousand cubic feet in 2001. Five-year averages are US$3.19 per thousand cubic feet for the NYMEX contract and $4.01 per thousand cubic feet for Alberta daily prices. Baytex received an average of $3.94 per thousand cubic feet for 2002 natural gas sales compared to $4.42 per thousand cubic feet in 2001.



(Price to Edmonton Par)
Baytex Heavy Oil



(mmcf/d)
Sales Portfolio – February 2003

Safety and Environment Safety and environmental issues continue to be a priority for Baytex. Companies have a responsibility to ensure that not only governmental regulations are being met, but also that future liabilities are being managed. The following is an overview of the initiatives that Baytex participates in and proactive actions being taken to manage its safety and environmental responsibilities.

The basis to ensure a safe and compliant corporate environment starts with the development of a safety and environmental program. Baytex has developed policies, procedures, and guidelines that all employees and contractors must follow. Continuous training for the Company's employees and contractors helps them to understand the requirements of the program. The success of the program is monitored through inspections and audits to ensure compliance and to assist in identifying areas that need further focus.

A waste management program is in place to ensure all oil field waste products are safely handled and properly disposed of. This program is manifested and tracked as part of the Company's ongoing internal procedures. When possible, products such as lube oil, filters and batteries are recycled. Baytex is also a member of the Western Canadian Spill Service organization. Spill clean-up equipment is available for use if a serious incident occurs and yearly spill clean-up exercises are held to educate employees and contractors on the proper use of this equipment.

Baytex has completed integrity evaluations of its oil and natural gas pipelines and ensured proper governmental certification of all of the Company's high-pressure vessels and field equipment. These programs ensure the longevity of our pipelines and equipment and protect the safety of our employees, the public and the environment.

Baytex conducts a large portion of its operations in caribou ranges throughout Alberta. To assist in the protection of the caribou, the Company has developed a caribou operating plan that has specific requirements for all of its operations in these highly sensitive environmental areas. Baytex is also a member of the Boreal Caribou Committee, which participates in many research initiatives to better protect caribou in Alberta.

Finally, Baytex takes part in the Canadian Association of Petroleum Producers' Environment, Health and Safety Stewardship program. This program is developed to set consistent safety and environmental standards throughout the western Canadian oil and gas industry and allows industry participants to measure the performance of their environment, health and safety program against other companies. Currently, Baytex is at a "Gold" ranking and continues to strive for excellence. Overall, Baytex continues to meet and exceed performance in safety and environmental initiatives, which could not be accomplished without the commitment of the Company's employees, contractors and management.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis should be read in conjunction with the Company's audited consolidated financial statements for the fiscal years ended December 31, 2002 and 2001. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Corporate Strategy As a mid-sized public Canadian oil and gas producer, Baytex focuses its attention on the low-cost development and production of its heavy oil and natural gas assets in the Western Canadian Sedimentary Basin. The Company emphasizes full-cycle exploration and development activity targeting operated, high working interest, heavy oil and natural gas reserves that can be discovered and produced quickly at a below average cost. Baytex enhances this activity with the strategic acquisition of corporations and individual properties that contain assets that are complementary to the Company's existing assets and, more importantly, provide significant development potential.

2002 Overview During the past year, Baytex focused on financial stability. A strategic divestiture program that began in the fourth quarter of 2001 and continued through the first quarter of 2002 significantly strengthened Baytex's financial position. The focus on financial stability continued throughout 2002 with a conservative capital-spending program that emphasized financial discipline, while successfully positioning the Company for future production growth. Exploration and development spending was enhanced by the key acquisition of heavy oil assets at Ardmore, Alberta in the fourth quarter. This acquisition provides significant heavy oil development opportunities for 2003 and beyond. In addition to the Ardmore purchase, the signing of a five-year, heavy oil supply agreement with a U.S.-based refining company further highlighted the Company's commitment to heavy oil. Commencing in 2003, this agreement allows Baytex to sell the majority of its heavy oil production at a fixed differential to benchmark WTI price, thereby significantly reducing the added volatility of the Company's cash flow from its heavy oil production.

Production The Company's average production for fiscal 2002 decreased by 10 percent to 39,214 barrels of oil equivalent per day from 43,488 barrels of oil equivalent per day for fiscal 2001. This decrease was the result of the property dispositions that occurred in the fourth quarter of 2001 and the first quarter of 2002 along with a decrease in capital spending on heavy oil in the last half of 2001.

Light oil production decreased 39 percent to 3,154 barrels per day during 2002 from 5,152 barrels per day in 2001. Heavy oil production

Production by Area

	Conventional Oil and NGLs *(bbls/d)*	Heavy Oil *(bbls/d)*	Natural Gas *(mmcf/d)*	Barrels of Oil Equivalent *(boe/d)*
2002				
Heavy Oil District	–	**23,967**	**10.5**	**25,710**
Plains District	**2,124**	–	**43.8**	**9,418**
Northern District	**1,030**	–	**18.3**	**4,086**
Total production	**3,154**	**23,967**	**72.6**	**39,214**
2001				
Heavy Oil District	368	26,533	11.5	28,813
Plains District	3,721	–	35.5	9,192
Northern District	1,063	–	23.8	5,483
Total production	5,152	26,533	70.8	43,488

during 2002 decreased by 10 percent to 23,967 barrels per day from 26,533 barrels per day during fiscal 2001. Natural gas production for 2002 increased by two percent to 72.6 million cubic feet per day compared to 70.8 million cubic feet per day for the prior year.

Revenue Petroleum and natural gas sales for 2002 increased by 11 percent to $365.9 million from $329.7 million for fiscal 2001. Benchmark WTI crude oil averaged US$26.08 per barrel for 2002, representing a one percent increase over the US$25.90 per barrel for 2001. Correspondingly, Baytex's light oil and NGLs price increased to $33.86 per barrel in 2002 from $33.65 per barrel in 2001. Baytex's heavy oil price increased 58 percent to $26.39 per barrel in 2002 from $16.69 per barrel, as heavy oil differentials decreased in 2002. The Company's heavy oil received 66 percent of the Canadian par crude price in 2002 compared to 43 percent in 2001. Natural gas prices were 11 percent lower in 2002 averaging $3.94 per thousand cubic feet compared to $4.42 per thousand cubic feet during the previous year. Overall, after accounting for financial derivative contracts, Baytex averaged $25.56 per barrel of oil equivalent for 2002 production, a 23 percent increase from $20.77 per barrel of oil equivalent received in the prior year.

For 2002, light oil revenue decreased 38 percent over 2001, as production decreased 39 percent while wellhead prices were consistent. Revenue from heavy oil increased 43 percent as the 10 percent decrease in production was offset by the 58 percent increase in wellhead prices. Natural gas revenue decreased nine percent as production increased two percent and wellhead prices declined by 11 percent.

Gross Revenue Analysis	2002		2001	
	($ thousands)	*($/unit)*	*($ thousands)*	*($/unit)*
Oil revenue *(barrels)*				
Light oil	**38,985**	**33.86**	63,288	33.65
Heavy oil	**230,874**	**26.39**	161,681	16.69
Derivative contract loss	**(10,622)**	**(1.07)**	(9,513)	(0.82)
Total oil revenue	**259,237**	**26.19**	215,456	18.63
Natural gas revenue *(mcf)*	**104,284**	**3.94**	114,244	4.42
Derivative contract gain	**2,339**	**0.09**	–	–
Total natural gas revenue	**106,623**	**4.03**	114,244	4.42
Total revenue (boe @ 6:1)	**365,860**	**25.56**	329,700	20.77

Operating Netbacks	Conventional Oil and NGLs *($/bbl)*		Heavy Oil *($/bbl)*		Total Oil & NGLs *($/bbl)*		Natural Gas *($/mcf)*		BOE *($/boe)*	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001	**2002**	2001
Sales price	**33.86**	33.65	**26.39**	16.69	**27.26**	19.45	**3.94**	4.42	**26.14**	21.37
Royalties	**(5.67)**	(6.44)	**(3.66)**	(1.77)	**(3.89)**	(2.53)	**(0.77)**	(1.11)	**(4.12)**	(3.64)
Operating costs	**(5.83)**	(6.82)	**(5.99)**	(5.59)	**(5.97)**	(5.79)	**(0.61)**	(0.64)	**(5.26)**	(5.26)
Operating netbacks	**22.36**	20.39	**16.74**	9.33	**17.40**	11.13	**2.56**	2.67	**16.76**	12.47

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

Royalties Total royalties increased two percent to $58.9 million for the year ended December 31, 2002 from $57.8 million for last year due to an increase in revenue and an increase in heavy oil royalty rates. The overall royalty rate for 2002 was 15.7 percent of sales compared to 17 percent of sales for fiscal 2001. The decrease in the overall royalty rate resulted from the sale of properties that carried a higher royalty burden. In 2002, royalties were 16.7 percent of sales for light oil (2001 – 19.1 percent), 13.9 percent for heavy oil (2001 – 10.6 percent) and 19.5 percent for natural gas (2001 – 25.1 percent).

Operating Expenses Operating expenses for 2002 decreased 10 percent to $75.2 million from $83.4 million during the previous year. This decrease is attributable to a 10 percent reduction in overall production. For 2002, operating expenses by product were $5.83 per barrel of light oil, $5.99 per barrel of heavy oil and $0.61 per thousand cubic feet of natural gas. In comparison, operating expenses by product for 2001 were $6.82 per barrel of light oil, $5.59 per barrel of heavy oil and $0.64 per thousand cubic feet of natural gas. Overall operating expenses were consistent on a unit basis at $5.26 per barrel of oil equivalent during 2002 and 2001.

General and Administrative Expenses General and administrative expenses, after capitalization, increased to $6.7 million for 2002 compared to $5.3 million for 2001. On a per-unit-of-production basis, these expenses increased to $0.47 per barrel of oil equivalent in 2002 from $0.33 per barrel of oil equivalent in 2001. This increase was due to higher staff levels associated with the Company's 2001 corporate acquisitions. In accordance with the full-cost accounting policy, $6.7 million of expenses were capitalized in 2002 compared to $5.3 million in 2001.

General and Administrative Expenses

($ thousands)	2002	2001
Gross corporate expense	**19,328**	16,504
Operator's recoveries	**(5,842)**	(5,980)
Subtotal	**13,486**	10,524
Capitalized expense	**(6,743)**	(5,262)
Net expense	**6,743**	5,262

Interest Expense For the year ended December 31, 2002, interest expense decreased to $25.2 million from $32.9 million for the prior year. Average debt levels decreased to $336.9 million in 2002 from $388.8 million in 2001. Interest expense was further reduced by interest rate swap agreements that the Company negotiated in December 2001. These swaps were settled during the third quarter of 2002 for total proceeds of $14.1 million, which is being amortized as a reduction of interest expense. This amortization reduces the effective interest rate of the senior secured notes from 7.23 percent to 5.7 percent until November 2004 and the senior subordinated notes from 10.5 percent to 9.2 percent until February 2006.

Depletion and Depreciation Depletion and depreciation, before ceiling test considerations, decreased to $106.8 million for 2002 compared to $132.9 million for 2001. The decrease is due to lower production and the ceiling test write-down taken at year-end 2001. On a unit-of-production basis, the provision for 2002 was $7.46 per barrel of oil equivalent compared to $8.37 per barrel of oil equivalent for last year.

($/boe)
Operating Expenses

Due to wide heavy oil differentials at year-end 2001, the Company incurred a $131.3 million ceiling test write-down (net of $103.2 million of future income taxes). This amount was recognized as additional depletion and depreciation for the year ended December 31, 2001.

Site Restoration Costs Site restoration costs for 2002 decreased to $2.8 million from $3.9 million last year due to lower production and property dispositions. On a unit-of-production basis, the provision for 2002 was $0.20 per barrel of oil equivalent compared to $0.25 per barrel of oil equivalent for the previous year.

Foreign Exchange Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") amended accounting standard with respect to foreign currency translation. The amended standard eliminates the practice to defer and amortize foreign exchange gains and losses on long-term monetary items. As a result, all foreign exchange gains and losses on long-term monetary items are now recognized in earnings based on the exchange rates at the end of the reporting periods. The amended standard also requires that prior years' comparative figures be restated to comply with the new standard.

The foreign exchange gain for the year ended December 31, 2002 was $2.7 million compared to a loss of $16.3 million for the prior year. The 2002 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.6331 at December 31, 2002 compared to 0.6279 at December 31, 2001. The 2001 loss is based on the translation of the U.S. dollar denominated senior secured notes at 0.6279 at December 31, 2001 compared to 0.6660 at December 31, 2000 along with the senior subordinated notes translated at 0.6279 at December 31, 2001 compared to 0.6582 on February 13, 2001 when the notes were issued.

Income Taxes Current tax expenses were $9.7 million for 2002 compared to $7.1 million in 2001. The current tax expenses are comprised of $8.1 million of Saskatchewan Capital Tax and $1.6 million of Large Corporation Tax, compared to $6.1 million and $1.0 million, respectively, for the prior year. Saskatchewan Capital Tax increased as higher commodity prices have resulted in higher revenues earned in Saskatchewan.

The fiscal 2002 provision for future income taxes was $38.0 million compared to recovery of $107.3 million for the prior year. The increase in future income taxes was the result of higher corporate earnings in 2002 due to increased commodity prices. Future income taxes for 2001 included a $103.2 million recovery associated with the year-end ceiling test write-down.

Cash Flow Netbacks	2002		2001	
	($/boe)	*(percent)*	*($/boe)*	*(percent)*
Production revenue	**26.14**	**100**	21.37	100
Derivative contract loss	**(0.57)**	**(2)**	(0.60)	(3)
Royalties	**(4.12)**	**(16)**	(3.64)	(17)
Operating expenses	**(5.26)**	**(20)**	(5.26)	(25)
Operating netbacks	**16.19**	**62**	11.87	55
General and administrative expenses	**(0.47)**	**(2)**	(0.33)	(1)
Interest expense	**(1.69)**	**(6)**	(2.02)	(9)
Current income taxes	**(0.68)**	**(3)**	(0.45)	(2)
Cash flow netbacks	**13.35**	**51**	9.07	43

Canadian Tax Pools
($ thousands)

	December 31, 2002
Cumulative Canadian Exploration Expense	123,000
Cumulative Canadian Development Expense	127,000
Cumulative Canadian Oil and Gas Property Expense	59,000
Undepreciated Capital Cost	150,000
Total tax pools	459,000

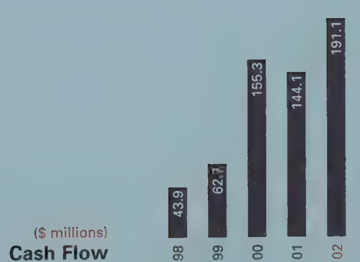
Cash Flow from Operations Cash flow from operations for the year ended December 31, 2002 increased 33 percent to $191.1 million from $144.1 million for the previous year, as a result of higher field netbacks. Field netbacks increased on a year-over-year basis due to higher oil prices. On a barrel of oil equivalent basis, cash flow from operations was $13.35 for 2002 compared to $9.07 for 2001.

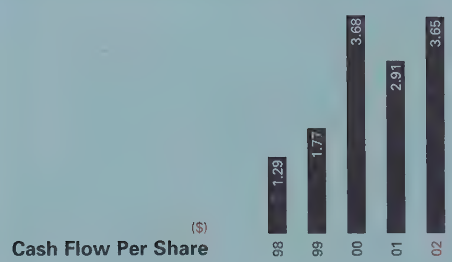
Capital Expenditures Total exploration and development expenditures for 2002 were $136.3 million, which is consistent with $135.9 million for 2001. Overall net capital expenditures decreased 66 percent to $126.5 million in 2002 from $375.9 million in 2001. Two corporate acquisitions were completed in the prior year, which accounted for $249.1 million of the 2001 expenditures.

Capital Expenditures
($ thousands)

	2002	2001
Land	13,834	11,494
Seismic	8,183	7,242
Drilling and completions	81,862	71,928
Equipment	24,507	37,206
Other	7,949	8,019
Total exploration and development	136,335	135,889
Corporate acquisitions	–	249,152
Property acquisitions	45,713	53,394
Dispositions	(55,580)	(62,582)
Net capital expenditures	126,468	375,853

Liquidity and Capital Resources At December 31, 2002, total net debt (including working capital) was $362.8 million compared to $379.1 million at December 31, 2001. The decrease in total debt at the end of 2002 was the result of cash flow from operations exceeding capital spending, proceeds from property dispositions, and proceeds received on the settlement of the interest rate swaps. The U.S. dollar denominated senior secured notes and senior subordinated notes decreased by a combined $2.7 million as a result of foreign exchange gains.





The Company's debt structure consists of three main components. The first component is the Company's senior credit facilities. At year-end, the Company had undrawn bank facilities with a total commitment of $77 million. These facilities are provided by a syndicate of chartered banks and are limited by a total senior funded debt borrowing base of $165 million. Total senior funded debt is defined to include the Company's senior secured term notes. Effective January 1, 2002, the CICA's Emerging Issues Committee issued an abstract giving guidance on disclosure of callable debt obligations. Specifically, the abstract requires the classification of borrowings under a 364-day revolving credit facility as current liabilities. The Company's bank loans are structured under this type of credit facility and, as such, the comparative balance at December 31, 2001 has been reclassified as current liabilities.

The second component is the senior secured notes which are due November 2004. These senior secured notes are governed by certain financial covenants measured at the end of each fiscal quarter. The principal covenants are: (i) consolidated tangible net worth not to be less than $200 million, excluding accounting ceiling test write-down (such net worth was $529 million as at December 31, 2002); (ii) consolidated total debt not to exceed 300 percent of consolidated cash flow (such ratio was 145 percent as at December 31, 2002); and (iii) consolidated cash flow not to be less than 400 percent of consolidated interest expense (such ratio was 892 percent as at December 31, 2002).

The final component is the US$150 million senior subordinated notes. These notes were issued in February 2001 and have a 10-year term. The notes bear interest at 10.5 percent payable semi-annually, are unsecured and have no financial maintenance covenants.

Baytex believes that cash flow generated from its operations, together with existing capacity under the bank facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the Company's capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Risk and Risk Management The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Company's control. Included in these risks are the uncertainty of finding new economically recoverable reserves, the fluctuation of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and Baytex competes with a number of other companies, many of which have greater financial and personnel resources.

The business risks facing Baytex are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. Baytex's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties, but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practise analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of proved petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and

natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates Baytex's properties annually to determine a fair estimate of reserves. A Reserve Evaluation Committee of the Board of Directors assists the Board in their annual review of the Company's reserve estimates.

The financial risks that Baytex is exposed to as part of the normal course of its business are managed with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Company's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, Baytex has a risk management program that may fix the price of oil and natural gas on a percentage of the Company's total expected production. The objective is to lock in prices on a portion of the Company's future production to decrease exposure to market volatility and ensure the Company's ability to finance its capital program. The Company recognizes gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

Baytex's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in US dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the Company's US dollar denominated term notes. The related foreign exchange gains and losses are included in net income.

Baytex is exposed to changes in interest rates as the Company's banking facilities are based on its lenders' prime lending rate and short-term Bankers' Acceptance rates. In December 2001, the Company entered into interest rate swap contracts converting the fixed rate on the US denominated term notes to a floating rate reset quarterly based on the three-month LIBOR rate. During 2002, the Company terminated all outstanding interest rate swap agreements for total proceeds of $14.1 million. This amount has been deferred and is being amortized as a reduction of interest expense over the original terms of the agreements. There is no plan at this time to fix the exchange rate on any of Baytex's long-term borrowings.

The Company's current position with respect to its financial derivative contracts is detailed in Note 12 of the Consolidated Financial Statements.

Critical Accounting Policies The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgements and estimates that affect the financial results of the Company. These critical estimates are discussed below.

Oil and Gas Accounting Baytex follows the full-cost accounting guideline to account for its crude oil and natural gas properties. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proven petroleum and natural gas reserves. Unit-of-production calculations are also used in the determination of the site restoration expense. By their inclusion in the unit-of-production calculation, reserve estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Company use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation and site restoration expense.

Impairment of Petroleum and Natural Gas Assets Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The ceiling test calculation utilizes and holds constant the prices and costs in effect at the end of the period. An estimate is made of the ultimate recoverable amount from future net revenues using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. The calculation of future net revenues in the ceiling test can be significantly impacted by fluctuations in any of these estimates. An impairment loss is recognized if the amount calculated under the ceiling test is less than the carrying costs of the Company's petroleum and natural gas assets and can result in a significant loss for a particular period.

New Accounting Pronouncements In November 2002, the CICA amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline establishes certain conditions where hedge accounting may be applied. It is effective for years beginning on or after July 1, 2003.

The CICA has amended the Handbook sections dealing with cash flow statements and earnings per share to restrict the disclosure of cash flow per share amounts in the financial statements. Under the amended standard, effective January 1, 2003, companies are no longer permitted to disclose cash flow per share amounts on either the face of the cash flow statement or in the notes to the financial statements.

In December 2002, the CICA issued a new standard on the accounting for asset retirement obligations. This standard requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized over its useful life. The liability accumulates until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004. Baytex is currently assessing the impact the adoption of this new standard will have on its consolidated financial statements.

Quarterly Information

	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial *(unaudited)*								
($ thousands, except per share amounts)								
Revenue	100,590	94,633	91,507	79,130	64,327	101,689	84,454	79,230
Cash flow from operations	53,116	48,637	49,208	40,125	24,353	46,330	35,770	37,617
Per share – basic	1.00	0.93	0.95	0.77	0.47	0.89	0.74	0.82
– diluted	0.99	0.91	0.93	0.76	0.47	0.87	0.72	0.80
Net income (loss)	12,791	3,687	21,354	7,304	(141,371)	(4,626)	10,583	(1,693)
Per share – basic	0.24	0.07	0.41	0.14	(2.71)	(0.09)	0.22	(0.04)
– diluted	0.24	0.07	0.40	0.14	(2.71)	(0.09)	0.21	(0.04)
Production								
Conventional oil and NGLs *(bbls/d)*	2,909	2,999	2,904	3,818	5,808	6,077	4,782	3,911
Heavy oil *(bbls/d)*	25,009	23,504	24,498	22,838	24,528	29,078	26,545	25,970
Total oil and NGLs *(bbls/d)*	27,918	26,503	27,402	26,656	30,336	35,155	31,327	29,881
Natural gas *(mmcf/d)*	71.8	71.3	73.3	73.7	75.9	78.2	71.3	57.6
Barrels of oil equivalent *(boe/d @ 6:1)*	39,890	38,391	39,625	38,948	42,990	48,187	43,201	39,483
Average Prices								
WTI oil *(US$/bbl)*	28.15	28.27	26.25	21.64	20.43	26.49	27.96	28.73
Edmonton par oil *($/bbl)*	42.81	44.02	40.40	33.51	31.00	40.37	42.19	43.00
BTE light oil *($/bbl)*	37.67	37.36	34.53	27.58	25.41	35.37	37.53	38.65
BTE heavy oil *($/bbl)*	26.09	31.03	26.64	21.58	10.39	23.75	16.77	14.62
BTE total oil *($/bbl)*	27.30	31.75	27.47	22.44	13.27	25.76	19.94	17.77
BTE natural gas *($/mcf)*	5.29	3.33	3.94	3.19	3.09	3.35	5.11	6.83
BTE oil equivalent *($/boe)*	28.64	28.10	26.29	21.39	14.82	24.23	22.88	23.41
Share Trading Information								
BTE – TSX								
High *($)*	8.92	8.40	8.45	6.89	5.25	11.50	13.55	14.84
Low *($)*	6.65	5.65	6.35	3.95	3.00	4.64	9.60	9.00
Close *($)*	8.48	7.59	7.20	6.85	4.37	4.80	9.80	12.15
Average daily volume	296,000	164,000	293,000	270,000	455,000	156,000	203,000	191,000

CONSOLIDATED FINANCIAL STATEMENTS

AS AT DECEMBER 31, [illegible]

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Ltd. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements. Their examination included a review and evaluation of Baytex's internal control systems and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Dale O. Shwed
President and Chief Executive Officer

Raymond T. Chan, CA
Senior Vice President and Chief Financial Officer

March 3, 2003

To the Shareholders of Baytex Energy Ltd.

We have audited the consolidated balance sheets of Baytex Energy Ltd. as at December 31, 2002 and 2001 and the consolidated statements of operations and deficit and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 3, 2003, we reported separately to the Board of Directors and shareholders of Baytex Energy Ltd. on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 17, United States Accounting Principles and Reporting and Note 18, Condensed Consolidated Financial Information.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta
March 3, 2003

As at December 31 *(thousands)*	2002	2001 (restated – see notes 2 & 4)
Assets		
Current assets		
Cash	$ 4,098	$ –
Accounts receivable	52,667	44,300
Properties held for sale	–	46,895
	56,765	91,195
Deferred charges and other assets	8,679	8,674
Petroleum and natural gas properties *(note 3)*	932,316	867,177
	$ 997,760	$ 967,046
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 92,563	$ 64,334
Bank loan *(note 4)*	–	73,820
Current portion of long-term debt *(note 5)*	–	2,000
	92,563	140,154
Long-term debt *(note 5)*	326,977	330,102
Deferred credits *(note 6)*	12,181	18,694
Provision for future site restoration costs	21,950	20,541
Future income taxes *(note 9)*	184,402	146,446
	638,073	655,937
Shareholders' Equity		
Share capital *(note 7)*	398,176	394,734
Deficit	(38,489)	(83,625)
	359,687	311,109
	$ 997,760	$ 967,046

See accompanying notes to the consolidated financial statements.

On behalf of the Board

John A. Brussa
Director

W. A. Blake Cassidy
Director

Years ended December 31 *(thousands, except per share data)*		2002		2001 (restated – see note 2)
Revenue				
Petroleum and natural gas sales	$	365,860	$	329,700
Royalties		(58,922)		(57,805)
		306,938		271,895
Expenses				
Operating		75,228		83,439
General and administrative		6,743		5,262
Interest *(note 5)*		25,217		32,942
Foreign exchange (gain) loss *(note 2)*		(2,691)		16,262
Depletion and depreciation *(note 3)*		106,834		367,384
Site restoration costs		2,799		3,912
		214,130		509,201
Income (loss) before income taxes		92,808		(237,306)
Income taxes (recovery) *(note 9)*				
Current		9,716		7,128
Future		37,956		(107,327)
		47,672		(100,199)
Net income (loss)		45,136		(137,107)
Retained earnings (deficit), beginning of year, as previously reported		(75,954)		52,555
Accounting policy change *(note 2)*		(7,671)		927
Retained earnings (deficit), beginning of year, as restated		(83,625)		53,482
Deficit, end of year	$	(38,489)	$	(83,625)
Net income (loss) per common share *(note 8)*				
Basic	$	0.86	$	(2.77)
Diluted	$	0.85	$	(2.77)

See accompanying notes to the consolidated financial statements.

Years ended December 31 *(thousands, except per share data)*	2002	2001
		(restated – see note 2)
Cash provided by (used in):		
Operating activities		
Net income (loss)	$ 45,136	$ (137,107)
Items not affecting cash:		
Site restoration costs	2,799	3,912
Amortization of deferred charges	1,052	946
Foreign exchange (gain) loss	(2,691)	16,262
Depletion and depreciation	106,834	367,384
Future income taxes (recovery)	37,956	(107,327)
Cash flow from operations	191,086	144,070
Change in non-cash working capital *(note 10)*	1,272	5,682
Increase in deferred charges	(1,057)	–
Increase (decrease) in deferred credits *(note 6)*	(18,694)	18,694
	172,607	168,446
Financing activities		
Issue of senior subordinated term notes	–	227,895
Decrease in bank loan and other debt	(76,254)	(88,474)
Increase in deferred charges	–	(9,037)
Increase in deferred credits *(note 6)*	12,181	–
Repurchase of common shares *(note 7)*	(55)	(860)
Issue of common shares	3,497	1,444
	(60,631)	130,968
Investing activities		
Corporate acquisitions *(note 14)*	–	(249,152)
Items not affecting cash		
Shares issued on acquisition	–	68,104
Assumption of long-term debt	–	36,356
Assumption of working capital	–	(2,734)
	–	(147,426)
Petroleum and natural gas property expenditures	(182,048)	(189,283)
Disposal of petroleum and natural gas properties	55,580	62,582
Properties held for sale	(46,895)	46,895
Change in non-cash working capital *(note 10)*	65,485	(72,182)
	(107,878)	(299,414)
Change in cash during the year	4,098	–
Cash, beginning of year	–	–
Cash, end of year	$ 4,098	$ –
Cash flow from operations per common share *(note 8)*		
Basic	$ 3.65	$ 2.91
Diluted	$ 3.59	$ 2.87

See accompanying notes to the consolidated financial statements.

Years ended December 31, 2002 and 2001 *(all tabular amounts in thousands, except per unit amounts)*

1. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles within the framework of the accounting policies summarized below:

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and partnership from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

Amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Company's reserve estimates are reviewed annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments accounted for at cost that have a maturity date of not more than 90 days.

Petroleum and Natural Gas Operations

The Company follows the full-cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs, along with estimated future costs that are based on current costs and that are incurred in developing proved reserves, are depleted and depreciated on a unit-of-production basis using estimated gross proved petroleum and natural gas reserves. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on sales of properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for Future Site Restoration Costs

Estimates are made of the future site restoration costs relating to the Company's petroleum and natural gas properties at the end of their economic life, based on year-end values, in accordance with current legislative requirements and industry practice. Annual charges are provided for on a unit-of-production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

Joint Interests

A portion of the Company's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

Foreign Currency Translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") amended accounting standard with respect to accounting for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Foreign denominated revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Deferred Charges

Financing costs related to the issuance of the senior secured term notes and the senior subordinated term notes have been deferred and are amortized over the term of the respective notes on a straight-line basis.

Financial Instruments

The Company formally documents its risk management objectives and strategies, including the permitted use of derivative financial instruments. The Company utilizes derivative financial instruments to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. All transactions of this nature entered into by the Company are related to an underlying financial position or to future petroleum and natural gas production. The Company does not use derivative financial instruments for trading purposes. Costs and gains on derivative contracts are recognized in income in the same period that the transactions are settled. The fair values of derivative instruments are not recorded in the balance sheet.

Gains and losses related to derivative financial instruments that have been closed prior to the settlement dates are deferred and recognized in the statement of operations over the original settlement period.

Future Income Taxes

Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Flow-through Shares

The Company has financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company records the gross carrying value of the expenditures and records a future tax liability for the tax benefits renounced to subscribers.

Stock-based Compensation

The Company's stock-based compensation plans are described in note 7. The Company accounts for employee stock options based on intrinsic values. No compensation expense is recognized when stock options are issued. The consideration paid on the exercise of stock options is credited to share capital. Benefits paid under the stock appreciation rights plan are charged to net income.

Per Share Amounts

Basic net income per share and basic cash flow from operations per share are computed by dividing net income and cash flow from operations by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options or warrants to purchase common shares were exercised. The treasury stock method is used to determine the dilutive effect of stock options and warrants, whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

2. CHANGES IN ACCOUNTING POLICY

Foreign Currency

Effective January 1, 2002, the Company retroactively adopted the CICA amended accounting standard with respect to accounting for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on the year ended December 31, 2002 was to increase net income by $1.8 million (2001 – decrease of $8.6 million). The effect of this change on the December 31, 2001 Consolidated Balance Sheet is an elimination of the unrealized foreign exchange loss of $13.7 million, a decrease in future income taxes of $6.0 million, and an increase in the deficit of $7.7 million.

Stock-based Compensation

Effective January 1, 2002, the Company adopted the new recommendations of the CICA with respect to stock-based compensation. In accordance with the new standard, the Company has elected to continue its policy of accounting for employee stock options based on intrinsic values and will disclose the pro forma results of using the fair value based method. The new recommendations apply to options granted after December 31, 2001.

3. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31	2002	2001
Petroleum and natural gas properties	$ 1,989,246	$ 1,817,273
Accumulated depletion and depreciation	(1,056,930)	(950,096)
	$ 932,316	$ 867,177

During 2002, $6.7 million (2001 – $5.3 million) of corporate expenses relating to exploration and development activities were capitalized. In calculating the depletion and depreciation provision for 2002, $80.3 million (2001 – $85.3 million) of costs relating to undeveloped properties and materials and supplies of $5.5 million (2001 – $7.1 million) were excluded from costs subject to depletion and depreciation.

As a result of the ceiling test performed at December 31, 2001, the Company recorded additional depletion and depreciation on its petroleum and natural gas properties of $234.5 million ($131.3 million net of income tax).

At December 31, 2002, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are $26.2 million (2001 – $30.0 million).

4. BANK LOAN

As at December 31	2002	2001
Bank loan	$ –	$ 73,820

The bank loan facilities consist of an operating loan and a 364-day revolving loan, which are provided by a syndicate of chartered banks. The facilities can be drawn in either Canadian or US funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities are subject to periodic review and are secured by a charge over all of the Company's assets. The security is shared *pari passu* with the senior secured term notes. At December 31, 2002, the facilities are limited to total commitment under the facilities of $77 million and a $165 million borrowing base of total senior funded debt, which is defined to include the senior secured term notes.

Effective January 1, 2002, the Company has classified borrowing under its bank facilities as a current liability as required by new CICA guidance. The bank loan at December 31, 2001 has been restated to conform to the current presentation.

5. LONG-TERM DEBT

As at December 31	2002	2001
Senior secured term notes (US$57 million)	$ 90,037	$ 90,778
Senior subordinated term notes (US$150 million)	236,940	238,890
Other long-term debt	–	2,434
	326,977	332,102
Less: current portion	–	2,000
	$ 326,977	$ 330,102

Senior Secured Term Notes

On November 13, 1998, the Company issued US$57 million of senior secured term notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. These notes are governed by financial and other corporate covenants and are secured by a charge over all of the Company's assets, which security is shared *pari passu* with the bank loan facilities. During 2002, the Company terminated an outstanding interest rate swap agreement associated with these notes. The gain from the settlement of this contract has been deferred and is being amortized as a reduction of interest expense over the original term of the agreement (note 6).

Senior Subordinated Term Notes

On February 12, 2001, the Company issued US$150 million of senior subordinated term notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank facilities and senior secured term notes. During 2002, the Company terminated outstanding interest rate swap agreements associated with these notes. The gain from the settlement of these contracts has been deferred and is being amortized as a reduction of interest expense over the original term of the agreements (note 6).

Interest Expense

The Company has incurred interest expense on its outstanding debt as follows:

	2002	2001
Bank loan	$ 760	$ 4,620
Amortization of deferred charges	1,052	946
Long-term debt	23,405	27,376
Total interest	$ 25,217	$ 32,942

6. DEFERRED CREDITS

As at December 31		2002		2001
Deferred interest rate swap settlement *(note 5)*	$	12,181	$	–
Deferred commodity contract gain		–		18,694
	$	12,181	$	18,694

In August 2002, the Company terminated all outstanding interest rate swap agreements for total proceeds of $14.1 million. This amount has been deferred and is being amortized as a reduction of interest expense over the original terms of the agreements.

During 2001, the Company renegotiated certain derivative contracts related to 2002 commodity prices and received a net payment of $18.7 million. This amount was recognized in income during 2002.

7. SHARE CAPITAL

Authorized

The Company has an unlimited number of common shares in its authorized share capital.

Issued

	2002			2001		
	Number of Shares		Amount	Number of Shares		Amount
Balance, beginning of year	52,008	$	394,734	45,797	$	326,767
Shares issued for corporate acquisitions *(note 14)*	–		–	6,119		68,104
Stock options exercised	820		3,497	314		1,444
Normal course issuer bid	(9)		(55)	(222)		(860)
Future tax related to flow-through shares	–		–	–		(721)
Balance, end of year	52,819	$	398,176	52,008	$	394,734

Stock Options and Stock Appreciation Rights

The Company grants stock options to its employees and directors at the market price of the common shares at the time of the grant. The options vest over three years and have a term of four years. At December 31, 2002, 3.7 million common shares (2001 – 4.6 million common shares) of the Company are reserved under the stock option plan for issuance. Of the 5.1 million options outstanding as of December 31, 2002, 1.4 million options are subject to shareholder ratification.

	Number of Options	Price Range	Weighted Average Exercise Price
Outstanding December 31, 2000	4,042	$3.30 to $15.50	$ 8.26
Granted	2,478	$3.51 to $13.30	$ 6.17
Exercised	(314)	$3.30 to $12.25	$ 4.84
Cancelled	(1,738)	$3.80 to $15.50	$ 11.25
Outstanding December 31, 2001	4,468	$3.30 to $10.75	$ 6.19
Granted	1,682	$4.40 to $ 7.97	$ 7.61
Exercised	(820)	$3.30 to $ 6.10	$ 4.27
Cancelled	(204)	$4.72 to $ 7.67	$ 5.78
Outstanding December 31, 2002	5,126	$3.51 to $10.75	$ 6.98

The following table summarizes information about the stock options outstanding at December 31, 2002:

	Number Outstanding at December 31, 2002	Weighted Average Remaining Term *(years)*	Weighted Average Exercise Price	Number Exercisable at December 31, 2002	Weighted Average Exercise Price
$3.51 to $ 5.00	2,029	2.2	$ 4.52	901	$ 4.27
$5.01 to $ 7.00	315	2.8	$ 6.61	77	$ 6.35
$7.01 to $ 9.00	1,712	3.4	$ 7.87	214	$ 8.76
$9.01 to $10.75	1,070	1.8	$ 10.32	713	$ 10.32
Total	5,126	2.5	$ 6.98	1,905	$ 7.12

The Company accounts for its stock options using intrinsic values. On this basis, compensation costs are not required to be recognized in the financial statements for stock options granted at market value. Had compensation costs for the Company's stock option plan been determined based on the fair-value method at the dates of grants under the plan after January 1, 2002, the Company's pro-forma net income for the year ended December 31, 2002 would have been reduced by $0.6 million and net income per share would be $0.85. The weighted average fair market value of options granted in 2002 was $3.65 per option. The fair value of the stock options granted is estimated on the grant date using the Black-Scholes option-pricing model using the following assumptions: risk-free interest rate of four percent; expected life of four years; and expected volatility of 57 percent.

The Company had granted stock appreciation rights ("Rights") to certain employees. Holders of the Rights were entitled to receive incentive payments based on the difference between market price of the Company's common shares and exercise price of the Rights. The exercise price of the Rights was determined based on the market price of the Company's common shares at the time the Rights were granted. The Rights vested over three years and had a term of four years. During 2002, all 202,334 remaining Rights (2001 – 6,666) were exercised. The related compensation expense has been included in general and administrative expenses.

Normal Course Issuer Bid

During the year ended December 31, 2002, the Company acquired 9,200 (2001 – 222,400) of its common shares through a normal course issuer bid program at an average cost of $6.03 per share (2001 – $3.87 per share). The shares purchased under the normal course issuer bid were cancelled. In January 2003, the Company renewed the normal course issuer bid to purchase up to 5.2 million common shares of the Company during the 12-month period beginning January 7, 2003 and ending January 5, 2004.

Flow-through Shares

In accordance with the terms of flow-through share offerings entered into by the Company, and pursuant to certain provisions of the *Income Tax Act* (Canada), the Company fulfilled its commitment to renounce, for income tax purposes, exploration expenditures of $1.6 million in 2001 to the subscribers of the flow-through shares.

8. NET INCOME AND CASH FLOW FROM OPERATIONS PER SHARE

The Company applies the treasury-stock method to assess the dilutive effect of outstanding stock options on net income and cash flow from operations per share. The number of shares used in the calculation of diluted net income and cash flow from operations per share is determined as follows:

	2002	2001
Weighted average number of shares outstanding, basic	52,298	49,503
Dilutive effect of stock options	939	701
Weighted average number of shares outstanding, diluted	53,237	50,204

The diluted net income and cash flow from operations per share discussed above did not include 2.8 million (2001 – 1.3 million) of stock options because the respective exercise prices exceeded the average market price of the common shares during the year.

9. INCOME TAXES

The provision for income taxes has been computed as follows:

	2002	2001
Income (loss) before income taxes	$ 92,808	$ (237,306)
Expected income taxes (recovery) at the statutory rate of 43.9% (2001 – 44.0%)	$ 40,743	$ (104,415)
Increase (decrease) in taxes resulting from:		
Crown royalties	21,153	19,870
Resource allowance	(26,308)	(22,560)
Alberta royalty tax credit	(219)	(224)
Rate change	(138)	183
Other	2,725	(181)
Large Corporation Tax and provincial capital tax	9,716	7,128
Provision for income taxes	$ 47,672	$ (100,199)

The components of future income taxes are as follows:

As at December 31	2002	2001
Future income tax liabilities:		
Capital assets	$ 202,429	$ 173,430
Future income tax assets:		
Abandonment costs	(9,638)	(9,038)
Attributed Canadian Royalty Income	(4,475)	(5,263)
Share issue costs	(2,833)	(4,398)
Loss carry-forward	(323)	(7,528)
Other	(758)	(757)
Future income taxes	$ 184,402	$ 146,446

10. CASH FLOW INFORMATION

Increase (Decrease) in Non-cash Working Capital Items

	2002	2001
Current assets	$ 38,528	$ (23,440)
Current liabilities	28,229	(43,060)
	$ 66,757	$ (66,500)

	2002	2001
Changes in non-cash working capital related to:		
Operating activities	$ 1,272	$ 5,682
Investing activities	65,485	(72,182)
	$ 66,757	$ (66,500)

During the year, the Company made the following cash outlays in respect of interest expense and current income taxes.

	2002	2001
Interest	$ 25,482	$ 22,889
Current income taxes (refund)	$ (3,298)	$ 15,459

11. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the balance sheet consist of accounts receivable, current liabilities and long-term borrowings. The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of financial instruments other than long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2002 and 2001, the reported values of the Company's senior secured term notes, bank loan and other long-term debt approximate their fair values. At December 31, 2002, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2001 – 95 percent).

12. DERIVATIVE CONTRACTS

The nature of the Company's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. In 2002, petroleum and natural gas sales were reduced by $8.3 million (2001 – $9.5 million) due to derivative contracts.

At December 31, 2002, the Company had derivative contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2003	2,500 bbls/d	US$20.00 – $26.05	WTI
Price collar	Calendar 2003	5,000 bbls/d	US$20.00 – $26.60	WTI
Price collar	Calendar 2003	2,500 bbls/d	US$20.00 – $27.00	WTI

The fair value of the oil derivative contracts at December 31, 2002 is an unrecognized liability of $12.3 million.

	Period	Amount	Exchange Rate	Unrecognized loss at December 31, 2002
Foreign currency swap	January 1998 to December 2005	US$315,000 per month	CAD/USD $1.4228	$2,008

13. COMMITMENTS

In October 2002, the Company entered into a long-term crude oil supply contract with a third party that requires the delivery of 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71 percent of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The volumes contracted under this contract will increase from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

For the period November 1, 2002 to October 31, 2003, the Company has entered into natural gas sales contracts with third parties for 15,000 GJ per day for fixed prices averaging $5.35/GJ and 10,000 GJ per day of collar contracts with prices between $4.20/GJ and $7.22/GJ.

14. CORPORATE ACQUISITIONS

Effective May 1, 2001, the Company acquired all of the issued and outstanding shares of OGY Petroleums Ltd. ("OGY"), a public company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration		
Cash	$	50,683
Transaction costs		3,100
		53,783
Issue of 1,169,481 common shares		14,057
	$	67,840
Net Assets Acquired		
Petroleum and natural gas properties	$	116,607
Future income taxes		(36,127)
Future site restoration costs		(1,844)
		78,636
Working capital deficiency		(4,809)
Long-term debt		(5,987)
	$	67,840

Effective June 1, 2001, the Company acquired all of the issued and outstanding shares of Triumph Energy Corporation ("Triumph"), a public company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration		
Cash	$	82,337
Transaction costs		11,306
		93,643
Issue of 4,949,245 common shares		54,047
	$	147,690
Net Assets Acquired		
Petroleum and natural gas properties	$	248,480
Future income taxes		(77,751)
Future site restoration costs		(213)
		170,516
Working capital		7,543
Long-term debt		(30,369)
	$	147,690

15. SUBSEQUENT EVENT

On March 3, 2003, the Company signed an agreement to sell certain crude oil and natural gas assets for total cash consideration of $133.3 million. The sale is subject to certain conditions and is scheduled to close by the end of March 2003. Upon closing of this transaction, the Company intends to use the proceeds for debt reduction and general corporate purposes.

16. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Company's Form 40-F, which is filed with the United States Securities and Exchange Commission.

	2002	2001	2000	1999	1998
Financial *($ thousands, except per share amounts)*					
Petroleum and natural gas sales	$ 365,860	$ 329,700	$ 286,226	$ 120,238	$ 103,115
Cash flow from operations	191,086	144,070	155,326	62,703	43,920
Per share – basic	3.65	2.91	3.68	1.77	1.29
Net income (loss)	45,136	(137,107)	41,682	16,485	(37,722)
Per share – basic	0.86	(2.77)	0.99	0.47	(1.10)
Capital expenditures, net	126,468	375,853	388,052	73,243	39,314
Total net debt	362,775	379,061	256,257	136,629	119,848
Total assets	997,760	967,046	829,227	419,163	413,809
Operations					
Production					
Conventional oil and NGLs *(bbls/d)*	3,154	5,152	4,107	4,457	5,475
Heavy oil *(bbls/d)*	23,967	26,533	20,005	5,574	3,517
Total oil and NGLs *(bbls/d)*	27,121	31,685	24,112	10,031	8,992
Natural gas *(mmcf/d)*	72.6	70.8	57.7	56.1	75.9
Barrels of oil equivalent *(boe/d @ 6:1)*	39,214	43,488	33,721	19,381	21,642
Reserves					
Crude oil and NGLs *(mbbls)*					
Proved	109,374	110,221	105,022	56,420	54,395
Probable	52,794	52,334	48,038	37,055	28,807
Total	162,168	162,555	153,060	93,475	83,202
Natural gas *(mmcf)*					
Proved	151,475	134,653	98,048	103,947	105,724
Probable	52,061	42,767	30,202	47,604	44,289
Total	203,536	177,420	128,250	151,551	150,013
Wells drilled *(gross)*					
Oil	106	63	267	109	91
Gas	51	81	28	28	47
Other	3	3	4	1	–
Dry	26	32	23	25	33
Total	186	179	322	163	171

Board of Directors

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W.A. Blake Cassidy
Retired Banker

Raymond T. Chan
Senior Vice-President
Baytex Energy Ltd.

Fred C. Coles
Independent Businessman

Dennis L. Nerland
Partner
Shea Nerland Calnan

Dale O. Shwed
President
Baytex Energy Ltd.

Officers

Dale O. Shwed
President and Chief Executive Officer

Raymond T. Chan, CA
Senior Vice-President and Chief Financial Officer

Ralph W. Gibson
Vice-President, Marketing

Daniel B. Horner, LLB
Vice-President, Land

John G. Leach, CA
Vice-President, Finance and Administration

S. Dale McAuley
Vice-President, Operations

Richard W. Naden
Vice-President, Production

Garry J. Wasylycia
Vice-President, Exploration

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

Head Office

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845
Website: www.baytex.ab.ca

Auditors

Deloitte & Touche LLP

Bankers

Royal Bank of Canada
Bank of Montreal
BNP Paribas (Canada)

Legal Counsel

Burnet, Duckworth & Palmer LLP

Reserves Engineers

Outtrim Szabo Associates Ltd.

Transfer Agent

Valiant Trust Company

Exchange Listing

Toronto Stock Exchange
Stock Symbol: BTE

Abbreviations

bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe	million barrels of oil equivalent (6 mcf: 1 bbl)
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids

Advisory

Certain statements in this Report are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995*. Specifically, this Report contains forward-looking statements relating to Management's approach to operations, expectations relating to amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, Company production, cash flow, debt levels, estimated amount and value of oil and gas reserves and estimated value of undeveloped land. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency and exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

Designed and produced by Parallel. Printed in Canada.

BAYTEX ENERGY LTD.
SUITE 2200, BOW VALLEY SQUARE II
205 – 5TH AVENUE S.W.
CALGARY, ALBERTA T2P 2V7
www.baytex.ab.ca